

# Mineral Royalties on Federal Lands: Issues for Congress

Updated January 19, 2015

Congressional Research Service

<https://crsreports.congress.gov>

R43891

## Summary

Three royalty debates may be revived in the 114<sup>th</sup> Congress: (1) whether to increase the statutory minimum rate for onshore federal oil and gas leases from 12.5% to 18.75%, (2) whether to enact revenue sharing laws for Outer Continental Shelf (OCS) leases to include all coastal states, and (3) whether to charge a royalty on hardrock locatable minerals produced on federal public domain lands. House and Senate bills in the 113<sup>th</sup> Congress proposed to raise the minimum rate from 12.5% to 18.75% on oil and gas produced on federal leases, provide for revenue sharing of OCS revenues, and establish a “gross proceeds” royalty on federally owned locatable mineral production.

### **Raising the Onshore Oil and Gas Royalty Rate**

A mineral royalty is a payment to the resource owner for the extraction of the mineral. Typically, in the mining industry the royalty is based on production (\$/ton) or income (percent of gross or net income). For federal oil and gas leases, royalties are assessed on the gross value of production minus allowable deductions. There is precedent for raising federal oil and gas lease royalty rates. Under the Bush Administration in 2008, Interior Secretary Dirk Kempthorne raised the deepwater rate for new leases from 12.5% to 16.67%. Then, in 2009, Secretary Ken Salazar of the Obama Administration increased the royalty rates for new offshore leases to 18.75%. The lower federal onshore royalty rate (12.5%) for oil and gas may be viewed as an incentive rate to encourage bidding on federal lands.

### **Revenue Sharing**

The largely decentralized revenue sharing system for onshore federal energy and mineral resources under the Mineral Leasing Act of 1920 provides states generally with a 50% share of revenues collected (rents, bonuses, and royalties), less 2% for administrative costs; Alaska, however, receives 90% of all revenues collected on federal onshore leases (less administrative costs). These onshore receipts are intended to maintain or establish infrastructure, and mitigate environmental, social, and other impacts from the development of mineral resources. This is different from the much more centralized system used for offshore revenue, which has much less revenue sharing.

### **Establish a Locatable Minerals Royalty**

The Mining Law continues to provide the structure for much of the western mineral development on public domain lands. Western mining, although not as extensive as it once was, is still a major economic activity. Industry officials argue that the current claim-patent system enhances a company’s ability to bring an economic deposit into production. They contend that restrictions on free access and security of tenure would curtail exploration. Mining Law critics consider the claim-patent system a giveaway of publicly owned resources because of the absence of royalties and the small charges associated with keeping a claim active and obtaining a patent.

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## Introduction

Three royalty debates may be revived in the 114<sup>th</sup> Congress: (1) whether to increase the statutory minimum rate for onshore federal oil and gas leases from 12.5% to 18.75%, (2) whether to enact revenue sharing laws for Outer Continental Shelf (OCS) leases to include all coastal states, and (3) whether to charge a royalty on hardrock locatable minerals produced on federal public domain lands.<sup>1</sup>

The onshore royalty rate for federal oil and gas leases has remained at 12.5% since the inception of the Mineral Leasing Act of 1920. If a lease produces oil or gas, a royalty is paid to the landowner on the value of extracted production. For federal onshore leases, lessees pay the statutory minimum of 12.5% on the value of production, but for offshore leases, royalty rates currently range from 12.5% to 18.75%.

There is currently no royalty on locatable minerals extracted from public domain lands. However, there is a 5% gross revenue royalty on minerals extracted from acquired federal lands.<sup>2</sup> This includes a relatively small amount of minerals produced in National Forests in some of the midwestern states.

Revenue sharing from OCS leases occurs under the Gulf of Mexico Energy and Security Act (GOMESA) enacted in 2006 (P.L. 109-432) for four Gulf coastal states: Louisiana, Texas, Alabama, and Mississippi. The states collect 37.5% of leasing revenues from selected leases off their coasts. Another revenue sharing feature of offshore leases allows the states to collect 27% of leasing revenues from leases within 3 miles beyond the states' offshore boundaries. A relatively small amount was disbursed to coastal states from offshore leases. For example, in FY2014, this share was about \$38 million out of nearly \$2.2 billion in total state onshore and offshore disbursements.

Oil and natural gas produced on federal lands account for 5% and 13% of total U.S. oil and gas production, respectively.<sup>3</sup> The volume and value of hardrock minerals produced on federal lands is unclear but some estimates have been made by the Government Accountability Office (GAO), the House Natural Resources Committee Democratic Staff, and the Department of the Interior.<sup>4</sup>

There is a significant amount of leasing revenue collected by the Office of Natural Resources Revenue (ONRR) within the Department of the Interior and disbursed to various states, the general Treasury, and specific funds such as the Land and Water Conservation Fund and the Reclamation Fund. Federal revenues from energy and mineral leases were estimated at \$14.4 billion in FY2013 by ONRR (using sales data), but have ranged from a low of about \$8.1 billion

<sup>1</sup> Besides the debate over increasing royalty rates and revenues for federal onshore minerals, Congress may also continue to focus on access to federal lands for mineral exploration, and the permitting process and timeline for mineral development.

<sup>2</sup> Public domain lands are those retained under federal ownership since their original acquisition by treaty, cession, or purchase as part of the general territory of the United States, including lands that passed out of but reverted to federal ownership. "Acquired" lands—those obtained from a state or a private owner through purchase, gift, or condemnation for particular federal purposes rather than as general territory of the United States—are subject to leasing only and are not covered by the 1872 Law. Some public lands may be "withdrawn" or closed to mineral entry.

<sup>3</sup> Budget Justifications, Bureau of Land Management, FY2015, p. VII-193.

<sup>4</sup> Democratic staff report: *Treasure for the Taking*, July 10, 2014. This report provided an estimated total sales value from federal public domain lands at \$4.56 billion in 2013. U.S. Department of the Interior, *Economic Implications of a Royalty System for Hardrock Minerals*, 1993, estimated that \$1.8 billion of hardrock locatable minerals were produced on public domain lands in 1992; U.S. Government Accountability Office, *Mineral Resources: Mineral Volume, Value and Revenue*, GAO-13-45R, November 15, 2012. The GAO cited the Department of the Interior estimates of 2011 sales value of nonfuel minerals on federal lands at \$6.41 billion.

in FY2004 to a high of about \$24.1 billion in FY2008, during the 10-year period (FY2004–FY2013). Changing prices for oil and gas are the most significant factors in the revenue swings. See the **Appendix** for details on revenues received and disbursed from mineral leasing programs and hardrock mining claims from FY2011 to FY2013.

House and Senate bills in the 113<sup>th</sup> Congress proposed to raise the minimum royalty rate from 12.5% to 18.75% on oil and gas produced on federal leases, improve the permitting process, provide for revenue sharing of OCS revenues, or establish a “gross proceeds” royalty on federally owned locatable mineral production.

This report serves as a primer on selected royalty issues debated by previous Congresses and likely to be faced in the 114<sup>th</sup> Congress.

## Why a Royalty?

Minerals (fuel and non-fuel) are an exhaustible resource; when extracted today they are unavailable for extraction at a later date. The miner must decide whether to produce now or in the future. If production occurs now, the miner must consider the value of foregone future production. Ideally a mineral producer would like to extract the resource so that the present value of its net income is the same for each production period. Mining firms must constantly explore for new minerals to replace those they have extracted.

A mineral royalty is a payment to the resource owner for the extraction of the mineral. In the mining industry the royalty is typically based on production (\$/ton) or income (percent of gross or net income). For federal oil and gas leases, royalties are assessed on the gross value of production minus allowable deductions. Royalties could be a significant portion of the overall costs of a mining operation and they could influence mining investment decisions. A wide range of income-based royalties are now applied to oil and gas production and hardrock mining on private and state-owned lands.

The federal government’s perspective is to generate revenue to fund society’s needs for the use of its resources and make payments available to states that are impacted. All mining companies want a stable, predictable ability to pay; early recovery of capital; and rates that do not distort production decisions (i.e., cut off grades or mine life) or add significantly to operating costs.

The mining industry is used to paying royalties; they are typically built into the firms’ cost structure. The issue is how an increase in the royalty rate or a new royalty would change the firms’ cost structure (lower-grade ores may become unprofitable after a royalty is imposed). The government objective of obtaining revenues from mining operations on federal lands may be balanced with the goal of maintaining a viable U.S. mining industry and meeting environmental requirements and social concerns.

## Oil and Gas Leasing and Royalty Rates

### Onshore

Development of oil and gas on federal lands is governed primarily by the Mineral Leasing Act of 1920 (MLA).<sup>5</sup> Leasing auctions and implementing activities are administered by the Bureau of

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<sup>5</sup> Mineral leasing for “coal, phosphate, sodium, potassium [potash], oil, oil shale, gilsonite (including all vein-type solid hydrocarbons), or gas” under all federal lands is governed by the Mineral Leasing Act of 1920 (30 U.S.C. §181) and

Land Management (BLM) for all federal lands. The MLA authorizes the Secretary of the Interior—through the BLM—to lease the subsurface rights to virtually all BLM and Forest Service (FS) lands that contain fossil fuel deposits, with the federal government retaining title to the lands.<sup>6</sup> The MLA authorizes both competitive and noncompetitive bidding processes for oil and gas exploration and production leases. In a competitive lease sale, a bonus payment is required to win the lease. Rents are then paid on a per-acre basis prior to production. The revenue associated with the onshore leasing process is collected and disbursed by ONRR.

Rental rates for onshore oil and gas leases start at \$1.50 per acre for the first five years then increase to \$2.00 per acre until production commences or the lease expires or is relinquished. Then royalty payments, based on the value of production, are made upon production. In addition to the MLA, the Energy Policy Act of 2005 (EPACT-05)<sup>7</sup> includes provisions governing access, leasing, and management of energy development on federal lands managed by the Bureau of Land Management and the Forest Service.<sup>8</sup>

## Raising Royalty Rates

There is precedent for raising federal oil and gas lease royalty rates (which the Secretary of the Interior has the authority to do). Under the Bush Administration in 2008, Interior Secretary Dirk Kempthorne raised the deepwater rate for new leases from 12.5% to 16.67%. Then, in March 2009, Secretary Ken Salazar of the Obama Administration increased the royalty rates for new offshore leases to 18.75%.

The 12.5% rate for federal onshore oil and gas leases appears low when compared to the state rate and the private sector rate, but there are upfront costs such as bonus bids involved in the purchase of a federal lease that increase the government's overall revenue stream. Most states have a statutory minimum rate of 12.5%, but actual state royalty rates are more likely 16.67% or 18.75% and can be as high as 25%. Private sector rates are typically around 18.75%.

The relatively low percentage of the total U.S. production coming from federal onshore lands may not likely translate into a major underpayment of revenues by the oil and gas industry as a whole, but higher royalty rates would translate into relatively significant amounts of money that would go back to the states.

The lower federal onshore royalty rate for oil and gas may be viewed as an incentive rate to encourage bidding on federal lands when competing for industry investment spending and to provide some balance from the disproportionate time it takes to process applications for permits to drill (APDs) on federal lands. This may be particularly significant when oil prices are declining.

Production on onshore federal lands is up as it is elsewhere onshore. Would a higher rate have made a difference in production? When Secretary Salazar increased the OCS new lease rate to 18.75%, he contended that there was no longer a need to keep the deepwater royalty rate at the minimum level because the royalty relief act had helped spur the technical change and innovations necessary for deep water drilling to be commercially viable. The incentives and high oil prices had worked and deepwater drilling and development had begun to move forward with

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the Mineral Leasing Act for Acquired Lands (31 U.S.C. §§351 et seq.).

<sup>6</sup> Exceptions include most BLM and FS lands classified as wilderness, lands incorporated in cities and towns, and lands that have otherwise been administratively or statutorily withdrawn from entry.

<sup>7</sup> P.L. 109-58.

<sup>8</sup> For further information, see CRS Report R40806, *Energy Projects on Federal Lands: Leasing and Authorization*, by Adam Vann.

great potential ahead for lease sales given the higher resource potential in the deepwater Gulf of Mexico. Production in the OCS has fluctuated over the past 10 years but was lower in FY2013 than FY2004.

One of the biggest deterrents to federal land development for oil and gas may be the timetable from lease purchase to drilling (exploration), discovery, and production. The leasing and permitting processes are dramatically different on private versus federal lands. One controversial issue has been the permitting process, considered by some to be too lengthy and cumbersome, particularly when compared to permitting for oil and gas exploration on private lands. The Energy Policy Act of 2005 (EPACT-05, P.L. 109-58) enacted several provisions that were aimed at expediting the development of oil and gas on public lands, particularly with respect to the approval of applications for permits to drill (APDs). Some critics of EPACT-05 believe that the permitting is now moving too fast without adequate environmental review. In addition to potential procedural deterrents, there may be better prospects on private land. Currently, most onshore oil and gas exploration and development activity is on privately owned land and state land.

There are still substantial amounts of oil and gas available on federal lands. Lower costs and high oil and gas prices (until recently) in general serve as an incentive to invest on public lands. Even though oil production on onshore federal lands has gone up over the past five years, albeit slowly, federal oil production is not proportional to its share of U.S. reserves (i.e., 5% of production; estimated at 15%-18% of reserves). Natural gas production from onshore federal leases has declined over the past five years. Onshore federal natural gas reserves account for about 21% of total U.S. natural gas reserves and 13% of U.S. production.

## Policy Options and Legislative Proposals

If they deem a change is necessary, lawmakers may continue to encourage the Administration to raise the onshore royalty rate but keep the statutory minimum at 12.5%, consistent with what was done for OCS leases. One group, the Center for Western Priorities,<sup>9</sup> supports increasing the statutory minimum rate from 12.5%, to as high as 18.75%. Does the Secretary simply raise the current onshore rate for new leases above the statutory minimum rate or seek an increase in the statutory minimum rate? A graduated rate increase over a five-year (or some other) period from 12.5% to 18.75% that would apply to new FY2016-FY2020 leases might also be considered. The Administration continues to evaluate royalty rate reforms among other federal oil and gas leasing program reforms.

What would justify a higher rate—improved technology, higher prices, a more efficient permitting process? Lower royalty rates for federal onshore leases may be justified to keep sustained interest in federal lands. An increase in royalty rates coupled with low oil or gas prices could impact high-cost marginal producers negatively.

Two bills introduced in the 113<sup>th</sup> Congress would have raised the statutory rate of federal oil and gas leases from 12.5% to 18.75%: S. 329 (Sustainable Energy Act); and H.R. 3574 (End Polluter Welfare Act of 2013).

<sup>9</sup> Center for Western Priorities, *A Fair Share: The Case for Updating Federal Royalties*, June 20, 2013. The Center for Western Priorities describes itself as a nonpartisan group that advances “responsible conservation and energy practices in the West.”



## Revenue Sharing from Federal Oil and Gas Leases

New royalty revenue sharing proposals have generally addressed allocating more revenues to the coastal states where offshore leases are held. This section on the OCS leasing system provides a framework for understanding how the offshore leasing program works.

### OCS Leasing System

The Outer Continental Shelf Lands Act (OCSLA) of 1953, as amended, provides for the leasing of OCS lands in a manner that protects the environment and returns revenues to the federal government in the form of bonus bids, rents, and royalties.<sup>10</sup> OCSLA requires the Secretary of the Interior to submit five-year leasing programs that specify the time, location, and size of the areas to be offered. Each five-year leasing program entails a lengthy multistep process that includes environmental impact statements. After a public comment period, a final proposed plan is submitted to the President and Congress.<sup>11</sup>

The offshore leasing and revenue system is managed by three agencies: the Bureau of Ocean Energy Management (BOEM), which administers the leasing of offshore tracts; the Bureau of Safety and Environmental Enforcement (BSEE); and the Office of Natural Resources Revenue, which manages the collection and disbursement of revenues, among other functions. All three of the entities are carrying out the functions of the former Minerals Management Service (MMS).<sup>12</sup>

### Revenue Sharing Systems

There are two major revenue sharing systems for federal oil and gas leases. One is used for onshore leases and another used for offshore leases. The largely decentralized<sup>13</sup> revenue sharing system for onshore federal energy and mineral resources under the Mineral Leasing Act of 1920 provides the states generally with a 50% share of revenues collected (rents, bonuses, and royalties), less 2% for administrative costs; Alaska, however, receives 90% of all revenues collected on federal leases.<sup>14</sup> The onshore mineral leasing program is administered by the Bureau of Land Management (BLM).

The decentralized onshore system also makes sizable contributions to the Reclamation Fund which is administered by the Bureau of Reclamation (BuRec). The Reclamation Fund, which

<sup>10</sup> 43 U.S.C. 1331 et seq.

<sup>11</sup> For details of the OCS oil and gas leasing framework, see CRS Report R40806, *Energy Projects on Federal Lands: Leasing and Authorization*, by Adam Vann.

<sup>12</sup> In response to the April 20, 2010, Gulf of Mexico oil spill, on May 11, 2010, Secretary of the Interior Ken Salazar announced a plan to separate the safety and environmental functions of the Minerals Management Service (MMS) from its leasing and revenue collection function. The goal was to improve the efficiency and effectiveness of the agency. Subsequently, on May 19, 2010, a decision was made by the Secretary to establish the following three new entities to perform the functions of the MMS: Bureau of Ocean Energy Management (BOEM), Bureau of Safety and Environmental Enforcement (BSEE), and the Office of Natural Resources Revenue (ONRR). Each of the three new entities has a director under the supervision of an assistant secretary.

<sup>13</sup> In this context, decentralized refers to a receipt-sharing system that allocates a larger portion of the receipts to the states, for state and local use. In contrast, a centralized system allocates a larger portion to the federal treasury for national use.

<sup>14</sup> Alaska does not receive allocations from the Reclamation Fund, so to equalize royalty treatment among the states, the Alaska Statehood Act and the Federal Land Policy and Management Act provide that Alaska's royalty share is 90% of the direct royalties, rather than 50%.



receives 40% of onshore federal mineral leasing receipts, provides funding for numerous water and irrigation projects in 17 western states.<sup>15</sup> Project funds must be appropriated annually by Congress. Generally, the Fund receives most of its funding from mineral leasing revenue, most of which comes from two states: Wyoming and New Mexico. Project funding is not based on where the leasing revenues originate, but on whether the projects are considered to be of high-value and, according to the BuRec, part of the United States' strategy to meet its water needs and address the current climate change challenges. The U.S. Treasury receives 10% of the onshore mineral leasing receipts annually.

These onshore receipts are intended to maintain or establish infrastructure, and mitigate environmental, social, and other impacts from the development of mineral resources. Also, it is a common practice that most states use much of these revenues to financially support their school systems. These onshore revenue payments are important to the states with federal mineral leases as substitutes for private taxes because of the tax-exempt status of federal property.

This is different from the much more centralized system used for offshore revenue. The largely centralized offshore revenue system has provided the U.S. Treasury with 80% or more annually of its total energy and mineral leasing revenue stream over the past several fiscal years. The coastal states, by contrast, have consistently received less than 2% of the total revenue generated from federal offshore leases, allocated under Section 8(g) of the Outer Continental Shelf Act, as amended. This centralized approach was slightly modified in 2006, under the Gulf of Mexico Energy Security Act (GOMESA, P.L. 109-432), which provided four coastal states 37.5% of the revenue generated from selected leases off their coasts. A small amount of GOMESA revenues have been allocated while the vast majority is set to be disbursed beginning in 2017. Beginning in FY2017, and thereafter, the Gulf producing states would also receive 37.5% of the revenues generated from leases awarded within the 2002-2007 planning area and from historical leases (described in the statute). There is an annual combined cap of \$500 million that can be awarded to the states. The Land and Water Conservation Fund (currently funded from OCS revenues) would receive 12.5% of the qualified revenues for state programs and the U.S. Treasury would receive 50% of those revenues.

Similarly to the onshore decentralized system, offshore revenues flow into entities unrelated to mineral and energy development for projects deemed by Congress, among many others, to be in the national interest and providing benefits to the general population. Revenues from the offshore leases are statutorily allocated among the coastal states, the Land and Water Conservation Fund (LWCF),<sup>16</sup> the National Historic Preservation Fund (HPF),<sup>17</sup> and the U.S. Treasury. States receive 27% of all OCS receipts closest to the shore (within 3 miles from the state coastal boundary) under Section 8(g) of the OCSLA amendments of 1985 (P.L. 99-272).<sup>18</sup> As noted above, this state share is about 2% of total federal offshore revenue.

<sup>15</sup> CRS Report R41844, *The Reclamation Fund: A Primer*, by Charles V. Stern.

<sup>16</sup> For details on the Land and Water Conservation Fund, see CRS Report RL33531, *Land and Water Conservation Fund: Overview, Funding History, and Issues*, by Carol Hardy Vincent.

<sup>17</sup> Under the National Historic Preservation Act (16 U.S.C. 470 et. seq.), the National Historic Preservation Fund is authorized to receive \$150 million annually from OCS receipts.

<sup>18</sup> The 8(g) revenue stream is the result of a 1978 OCSLA amendment that provides for a "fair and equitable" sharing of revenues from Section 8(g) common pool lands. These lands are defined in the amendments as submerged acreage lying outside the standard three-nautical-mile state-federal demarcation line, typically extending to a total of 6 nautical miles offshore (or 3 miles beyond the state's boundary) but that include a pool of oil common to both federal and state jurisdiction. The states' share of the revenue (27%) was established by the OCSLA amendments of 1985 (P.L. 99-272) and is paid directly to the states. Payments to the states previously had been placed in escrow, which were then paid out

## OCS Revenue Sharing Analysis

Proposals have been made to use OCS revenue receipts to provide support directly to all states that have oil and gas drilling and development off their coasts, similar to the allocation under the onshore system, even though actual production in the OCS and deepwater regions occurs strictly within federal jurisdiction; there are no lost private taxes for the offshore federal lands. Other congressional arguments assert that the revenue is for the general public good, not necessarily to benefit any particular state.

Advocates of greater OCS revenue sharing contend that projects in the affected coastal states that might be funded from OCS revenues would likely provide benefits to the national economy and the general public. Oil and gas production alone is viewed by many as vital to the national economy and energy security.

States have argued for a greater share of the OCS revenues based on the significant impact of oil and gas activities on their infrastructure and the environment. According to the coastal producing states, the revenues are needed to mitigate environmental impacts and to maintain the necessary support structure for the offshore oil and gas industry. These costs may be incurred indirectly from events (e.g., a hurricane or flood) that require maintenance to ensure continual offshore activity. Infrastructure costs include roads, water and waste facilities, pipelines, storage facilities, disposal facilities, public safety, and education. Protection and conservation of coastal states' ecosystems include barrier islands, marshes, etc., to protect near-shore facilities. How are these impacts and costs built into the cost structure of the producing firm? One way is to consider a firm's payment (a royalty) to the federal government as a payment for the use of state and local resources and for the extraction of oil and gas.

Issues such as hurricane protection, rebuilding from the impacts of a hurricane, and rebuilding barrier islands are considered vital to the economic interest of the states affected. Without any federal revenue-payments for these associated costs, they must be absorbed by the state.

Firms that develop resources offer significant external benefits as well. They may compensate some states with employment opportunities (direct and indirect jobs) that become available in the oil and gas industry. These businesses and employees in related fields pay taxes, make investments, and support local economies. This, however, may be insufficient to cover the full impact of the industry, states contend. Those revenues generated by related industry may be spent within the state but may not necessarily be spent to mitigate impacts and prevent infrastructure erosion. On balance, states argue, external costs may outweigh the external benefits for coastal states. However, such a cost/benefit determination is beyond the scope of this report.

## Policy Options and Legislative Proposals

The states' view along with that of some Members of Congress is that the federal Treasury could share part of its revenues with the states to address the issue of external costs associated with offshore development. Alternatively, the states could impose a user fee. However, the offshore revenue system does not necessarily need to mirror the onshore system (states receiving 50% of the revenue generated within that state, 40% going to the Reclamation Fund, and the federal Treasury receiving 10%). These offshore acres are not tax-exempt federal properties within a state's boundaries but rather waters located entirely on the federal OCS and deepwater regions. A

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between 1986 and 2001. A dispute over what was meant by a "fair and equitable" division of the 8(g) receipts was settled by the 1985 OCSLA amendments.

“fair and equitable” revenue system could, in principle, provide a percentage of the total, sufficient to address the costs these states incur.

The “fair and equitable” payment may be a fixed amount of revenue related to the external costs rather than a fixed percent of the total revenue. Or the percent could reflect the needs of both the states and the federal treasury and not necessarily be tied to the onshore system. Fifty percent of offshore revenues is a substantially larger amount than 50% of the onshore revenue stream and would be allocated to a smaller number of states. The policy decision is to determine if the states should receive a revenue-based payment, and if they do, what would be the optimal amount to address those production costs incurred by the states as part of OCS oil and gas development. Further analysis is needed on what an optimal level of federal support would be for the states’ supportive role in offshore development.

Among the legislative proposals in the 113<sup>th</sup> Congress that included revenue sharing provisions were H.R. 2 (American Energy Solutions for Lower Costs and More American Jobs Act); H.R. 1165 (Maximize Offshore Resources Exploration Act of 2013); and H.R. 4956 (American Energy Opportunity Act of 2014). None of these bills were enacted into law.

## **Hardrock Minerals—Location System and Fee Structure**

### **Mining on Federal Lands**

Mining of hardrock minerals on federal lands is governed primarily by the General Mining Law of 1872. The original purposes of the Mining Law were to promote mineral exploration and development on federal lands in the western United States, offer an opportunity to obtain a clear title to mines already being worked, and help settle the West. The Mining Law grants free access to individuals and corporations to prospect for minerals on open public domain lands, and allows them, upon making a discovery, to stake (or “locate”) a claim on the deposit. A valid claim entitles the holder to develop the minerals. The 1872 Mining Law originally applied to all valuable mineral deposits except coal (17 Stat. 91, 1872, as amended).

The Mining Law continues to provide the structure for much of the western mineral development on public domain lands. Western mining, although not as extensive as it once was, is still a major economic activity, and a high percentage of hardrock mining is on public lands.

### **The Claim-Patent System**

As of September 1, 2014, to hold a claim on public land, claimants must pay an annual maintenance fee of \$155 per claim.<sup>19</sup> Claimants with 10 claims or fewer may file for a waiver of the annual maintenance fee and perform annual assessment work instead. There also is a \$37 fee for first-time locators to locate and record a claim.<sup>20</sup> The fees above are to be adjusted every five years based on the Consumer Price Index (30 U.S.C. 28 j (c)). The next adjustment is projected to be made on September 1, 2019.<sup>21</sup> The annual maintenance fee replaces the requirement that \$100 of annual development work be conducted per claim.

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<sup>19</sup> 30 U.S.C. 28f

<sup>20</sup> 30 U.S.C. 28g

<sup>21</sup> Federal Register, Required Fees for Mining Claims and Sites, June 30, 2014.

Once a claimed mineral deposit is determined to be economically recoverable, and at least \$500 of development work has been performed, the claim holder had the right to file a patent application to obtain title to surface and mineral rights. Beginning January 3, 1989, a fee of \$250 per patent application plus \$50 per claim within each application had been required. If the patent application is approved, the claimant had the right to purchase surface and mineral rights at a rate of \$2.50 per acre for placer claims and \$5 per acre for lode claims.<sup>22</sup> These per-acre fees were substantial when the Mining Law was enacted; claimed land and minerals now far exceed these amounts in value.

The following provisions currently apply to mining claims:

- there is no limit on the number of claims a person can locate;
- there is no requirement that mineral production ever commence;<sup>23</sup>
- mineral production can take place without a patent or royalty payments to the federal government; and
- claims can be held indefinitely with or without mineral production.

Beginning in FY1995, Congress has enacted (in the Interior appropriations laws) a series of one-year moratoria on the issuance of mineral patents. However, applications meeting certain requirements that were filed on or before September 30, 1994, are allowed to proceed, and third-party contractors are authorized to process the mineral examinations on those applications. The patent moratorium will not stop the production of valuable mineral resources from the public lands, but will prevent the further transfer of ownership of public lands to the private sector (with the exception of the 237 patent applications already in the pipeline).<sup>24</sup>

The annual one-year moratorium on patenting continues along with the uncertainty over whether efforts will continue to try to reform the 1872 Mining Law. The mining industry would like to end the uncertainty to facilitate its long-term business planning. Environmentalists, who were hoping for new environmental protection language in a major mining law reform bill, argue that the patent moratorium does not protect the environment from current mining practices.

## Types of Hardrock Mineral Royalties

The two types of royalties being debated generally include gross proceeds/net smelter return royalty and a net income royalty.

A gross proceeds (income) royalty or similarly a net smelter returns royalty is based on the gross revenue minus smelting charges and transportation costs and other allowable costs. This type of royalty would generally guarantee royalty revenues when production occurs. Collections and administration are relatively simple and inexpensive. The royalty would apply even when the operation was unprofitable; if it caused the mine to shut down, all royalties would be lost. Assessing royalties at the smelter stage could also lead to mining only the highest quality ore. The added costs could cause some mines to be uneconomic.

<sup>22</sup> A placer deposit is an alluvial deposit of valuable minerals usually in sand or gravel; a lode or vein deposit is of a valuable mineral consisting of quartz or other rock in place with definite boundaries. A placer claim is usually limited to 20 acres but a lode claim may be slightly greater than 20 acres. Source: *Dictionary of Mining, Mineral and Related Terms*, Bureau of Mines, 1968.

<sup>23</sup> However, before the enactment of P.L. 102-381, claimants were required to conduct at least \$100 of development work per year.

<sup>24</sup> P.L. 103-332

A net income royalty would be applied after all costs were subtracted from gross income and would be based on profitability of the mine. This royalty would focus not on gross production but on the operation's economic rent; that is, any profit in excess of that necessary to maintain the mine in operation. The net income royalty would be expected to have less impact on marginal mines, and thus be less likely to shut them down. One disadvantage with this type of royalty is that it would require a much higher percentage royalty to achieve the same level of revenue flow. In addition, when there are no profits, there are no royalties, unlike the net smelter royalty. The mining industry argues that this is "socially equitable," because the royalty is applied to what it defines as excess profits or rents. A net income royalty could be difficult to administer and subject to "creative accounting," meaning that firms could increase deductions to show little or no net profits, thus avoiding payment of the royalty.

## **Analysis**

The right to enter the public domain lands and prospect for and develop minerals is the feature of the claim-patent system that draws the most vigorous support from the mining industry. Modern hardrock mineral exploration requires a continuous effort using vast tracts of land and sophisticated and expensive technology. Industry officials argue that being able to obtain full and clear title to the land enhances a company's ability to bring an economic deposit into production; financing the project, for example, may be more feasible. They contend that restrictions on free access and security of tenure would curtail exploration efforts among large and small mining firms. In their view, the incentive to develop would be lost, long-run costs would increase, and the industry and the country would suffer.

Mining Law critics consider the claim-patent system a giveaway of publicly owned resources because of the small charges associated with keeping a claim active and obtaining a patent and the absence of royalties. They maintain that although such generous terms may have been effective ways to help settle the West and develop minerals, there is no solid evidence that under a different system, minerals would not be developed today. They also believe the current system, by conveying title and allowing other uses of patented lands, creates difficult land management problems through the creation of private inholdings on public land, and that current law does not provide for adequate protection of the environment.

In the claim-patent system, mineral claims may be held indefinitely without any mineral production. Once lands are patented to convey full title to the claimant, the owner can use the lands for a variety of purposes, including non-mineral ones. However, using land under an unpatented mining claim for anything but mineral and associated purposes violates the Mining Law. Critics believe that many claims are held for speculative purposes. However, industry officials argue that a claim may lie idle until market conditions make it profitable to develop the mineral deposit.

The industry generally opposes placing hardrock minerals under a leasing system because this would give the federal government discretionary control over development, impose royalty payments, and retain government ownership of surface and/or mineral rights.

## **Policy Options and Legislative Proposals**

The policy debate on federal lands used for hardrock mineral development focuses on whether a royalty will be charged at all. There is currently no royalty payment required to the federal government for minerals extracted from federal public domain lands. There is ongoing congressional debate over the following:

- whether to place selected minerals (e.g., gold, copper, and silver) in a leasing system and charge a royalty, perhaps even a sliding scale royalty based on prices;
- alternatively, whether to retain the claim-patent system, adding a royalty to production costs;
- whether to establish a gross income royalty or a net income royalty; the most vigorous debate has centered on this issue;
- whether to establish a gross income royalty of 8% on the production of locatable minerals from new mining claims and 4% of gross income on production from certain existing claims. A legislative proposal in the 113<sup>th</sup> Congress, H.R. 5060 (Hardrock Mining and Reclamation Act of 2014), included these provisions; this proposal was not enacted; and
- an Administration proposal to establish a leasing process (under the Mineral Leasing Act of 1920) for certain hardrock locatable minerals, including a gross proceeds royalty of not less than 5% on the value of production for new leases. Existing mining claims would be exempt from the new leasing process.

## Appendix. Federal Onshore and OCS Revenues

### Onshore Leasable Minerals

#### Receipts

Receipts from leasing are collected by the DOI ONRR. For oil and gas, areas identified as known geological structures are offered for lease competitively; for areas with bids less than the identified minimum or outside known geological structures, leases may be offered to applicants without competition for a \$75 application fee (in lieu of a bonus bid).

- **Bonus Bids**—Competitive bonus bidding is used for lease sales, with leases awarded to the highest bidder. A minimum acceptable bonus bid is determined by BLM (based on their economic analysis of fair market value) for each tract offered. Successful bidders make an up-front cash payment, called a bonus bid, to secure the lease.
- **Rents**—Administratively determined annual payments are charged per acre leased until production commences or the lease is terminated or relinquished.
- **Royalties**—Payments of a share of production are made, generally set at 12.5% of the value of production. The Secretary of the Interior may reduce or eliminate the royalty established by the lease to promote increased recovery.
- **Permit Fees**—Administratively determined fees are charged for filing applications for permits to drill. The fees are intended to recover administrative costs of permit processing

**Table A-1. Receipts from Onshore Mineral Leasing**  
(in millions of dollars)

	FY2011	FY2012	FY2013
Bonus Bids	492.0	626.5	652.2
Annual Rents	50.6	48.6	45.3
Royalties	3,703.8	3,466.2	3,577.1
Permit Fees/Other <sup>a</sup>	31.7	(14.8)	22.4
Total	4,278.1	4,126.5	4,297.0

**Source:** U.S. Dept. of the Interior, Office of Natural Resources Revenue, *Federal Onshore Reported Royalty Revenues*, <http://www.onrr.gov/ONRRWebStats/FedOffReportedRoyaltyRevenues.aspx?yeartype=FY&year=%202010&dateType=AY#> (by sales year as of February 5, 2014).

- a. According to ONRR, the net negative amount for Permit Fees /OtherFY2012 is the result of “negative reporting lines in a few states.”

#### Disposition of Receipts

- **Payments to States, except Alaska** (Mineral Leasing Act of 1920; 30 U.S.C. §191)—50% of receipts are permanently appropriated to the states.



- **Reclamation Fund**—40% of receipts, except in Alaska, are deposited in the Reclamation Fund; expenditures require an annual appropriation.<sup>25</sup>
- **Payments to Alaska** (Mineral Leasing Act of 1920; 30 U.S.C. §191, as amended by P.L. 85-505)—90% of receipts from leases in Alaska are permanently appropriated to the state.
- **Federal Administrative Costs**—2% of the states' share (1% of receipts, except for 1.8% of receipts in Alaska) is retained and permanently appropriated to the BLM to cover administrative costs of the leasing program, under language in the Interior appropriation bills since FY2008.
- **General Treasury**—The remaining 10% of receipts is deposited in the Treasury.

## Offshore Leasable Minerals

### Receipts

Leasing minerals (primarily oil and gas) under the federal Outer Continental Shelf (OCS, typically from 3 to 200 miles offshore) is governed by the 1953 Outer Continental Shelf Lands Act (OCSLA, 43 U.S.C. §§1301, et seq.).<sup>26</sup> The DOI BOEM prepares five-year leasing plans and periodically offers leases at auction.<sup>27</sup>

- **Bonus Bids**—Competitive sealed bonus bidding is used for lease sales, with leases awarded to the highest bidder. Successful bidders make an up-front cash payment, called a bonus bid, to secure the lease. A minimum acceptable bonus bid is determined by BOEM (based on their economic analysis of fair market value) for each tract offered. In contrast to onshore oil and gas leasing, if no bids match or exceed the minimum, the lease is withheld, to be offered again at a later sale.
- **Rents**—Administratively determined annual payments are charged per acre leased for nonproducing active leases.
- **Royalties**—Payment of a share of production is made by the successful bidder. Royalty rates are generally set at 12.5%, 16.7%, or 18.75% of the value of production, with the highest rate used in recent offshore lease sales. The Secretary of the Interior may reduce or eliminate the royalty established by the lease to promote increased recovery.
- **Permit Fees**—Administratively determined fees are charged for filing and maintaining permits.

<sup>25</sup> The Reclamation Fund was originally designed to collect various receipts to finance Bureau of Reclamation projects. Expenditures from the fund require annual appropriations; funds not appropriated are credited to the Reclamation Fund as unappropriated receipts.

<sup>26</sup> See CRS Report RL33404, *Offshore Oil and Gas Development: Legal Framework*, by Adam Vann.

<sup>27</sup> For a discussion of the controversies over OCS leasing in recent years, see CRS Report RL33493, *Outer Continental Shelf: Debate Over Oil and Gas Leasing and Revenue Sharing*, by Marc Humphries.

**Table A-2. Receipts from Offshore Mineral Leasing**

(in millions of dollars)

	FY2011	FY2012	FY2013
Bonus Bids	37.1	606.4	2,733.0
Annual Rents	224.9	230.4	250.0
Royalties	6,253.5	6,014.7	6,169.9
Permit Fees	5.0	4.6	34.6
Total	6,520.5	6,856.1	9,187.5

**Source:** U.S. Dept. of the Interior, Office of Natural Resources Revenue, *Total Federal Offshore Reported Royalty Revenues*, <http://www.onrr.gov/ONRRWebStats/FedOffReportedRoyaltyRevenues.aspx?yeartype=FY&year=%202010&dateType=AY#> (by sales year as of February 5, 2014).

## Disposition of Receipts

- **Land and Water Conservation Fund** (LWCF, P.L. 88-578; 16 U.S.C. §§4601-4, et seq.)<sup>28</sup>—Up to \$900 million annually is allocated to the LWCF. It receives deposits from several sources, such as surplus federal property sales and federal motorboat fuel taxes, and then revenues from OCS leasing to fulfill the \$900 million annual authorization; expenditures require an annual appropriation.
- **National Historic Preservation Fund** (National Historic Preservation Act, P.L. 89-665; 16 U.S.C. §§470, et seq.)—\$150 million annually from OCS lease receipts is allocated to the fund; expenditures require an annual appropriation.
- **Section 8(g) Payments to States** (§8(g) of the OCSLA Amendments of 1985, P.L. 99-272)—27% of receipts from §8(g) common pool lands is permanently appropriated to the states; §8(g) common pool lands are defined as submerged acreage lying outside the 3-nautical mile state-federal demarcation, typically extending to a total of 6 nautical miles offshore but including a pool of oil common to both federal and state jurisdiction. A 1978 OCSLA amendment provides for “fair and equitable” sharing of revenues from §8(g) common pool lands.
- **Section 8(p) Payments to States** (Gulf of Mexico Energy Security Act (GOMESA) of 2006, P.L. 109-432, amending OCSLA)—37.5% of receipts from specified federal oil and gas leases off the coasts of selected Gulf states is permanently appropriated to those states (Alabama, Louisiana, Mississippi, and Texas; no leasing occurs off the Florida coast).
- **LWCF, Stateside Program** (GOMESA)—12.5% of receipts from specified federal oil and gas leases off the coasts of selected Gulf states is permanently appropriated to the National Park Service to be used consistent with the stateside program under the LWCF Act.
- **Coastal Impact Assistance Program** (CIAP, Energy Policy Act of 2005, P.L. 109-58, §384)—\$250 million of annual spending for FY2007-FY2010 was permanently appropriated, 65% to coastal producing states (Alabama, Alaska, California, Louisiana, Mississippi, and Texas) and 35% to eligible political

<sup>28</sup> The vast majority of LWCF funding is derived from OCS revenues. See CRS Report RL33531, *Land and Water Conservation Fund: Overview, Funding History, and Issues*, by Carol Hardy Vincent.

subdivisions, allocated among states by the formula in law (based on previous qualified OCS revenues).

- **General Treasury**—Any remaining funds are deposited in the Treasury.

## Hardrock/Locatable Minerals

### Receipts

The General Mining Law of 1872 established a system of free access for individuals and corporations to prospect for hardrock (or locatable) minerals (e.g., gold, silver, copper) on open federal lands and to stake a claim on the deposit (30 U.S.C. Chapter 2).<sup>29</sup> The minerals can then be extracted from sites with valid claims. The claim can be “patented” to transfer title to the relevant lands to the claimant, although patenting the land is not necessary to extract the minerals. Since FY1995, Congress has included a provision prohibiting land patents under the General Mining Law in the annual Interior appropriations acts. Receipts from hardrock/locatable minerals are generated from fees to locate the claim, an annual fee to maintain the claim, and a per-acre fee to patent the claim.<sup>30</sup>

- The location fee is \$37 per claim to locate and record the claim.
- The annual maintenance fee is \$155 per claim. This fee replaces the previous annual requirement of \$100 of development work to maintain each claim. Claimants with 10 claims or fewer may file to waive the annual maintenance fee and perform the annual work assessment instead.
- Fees are adjusted every five years for inflation, based on the Consumer Price Index.
- Patenting the claim (which has been prohibited under a provision in the annual Interior appropriations acts since FY1995) includes two fees:
  - Patent application fee is \$250, plus \$50 for each claim in the application.
  - Land patent fee is \$2.50 or \$5.00 per acre, depending on the type of claim.

**Table A-3. Receipts from BLM Hardrock Mining Fees**  
(in millions of dollars)

FY2011	FY2012	FY2013
65.0	66.0	67.0

**Source:** U.S. Dept. of the Interior, Bureau of Land Management, *FY2015 Budget Justifications*, p. 195, annual series.

<sup>29</sup> The 1872 Mining Law and subsequent statutes governing mining on federal lands do not define hardrock or locatable minerals subject to their provisions. Legislation in the 111<sup>th</sup> Congress to modify federal mining administration (e.g., H.R. 699, H.R. 3201, and S. 796) would have defined locatable minerals as those not subject to mineral and geothermal leasing laws (30 U.S.C. §§181 et seq., §§351 et seq., and §§1001 et seq.) or the Mineral Materials Act of 1947 (30 U.S.C. §§601 et seq.). Leasable minerals are discussed in this section; mineral materials are essentially low-grade construction materials, such as sand, gravel, and crushed rock, and are not discussed in this report.

<sup>30</sup> See CRS Report RL33908, *Mining on Federal Lands: Hardrock Minerals*, by Marc Humphries.

## Disposition of Receipts

- ***Cost of Collections*** (P.L. 111-8, FY2009 Omnibus Appropriations Act at 123 Stat. 701)—The BLM is authorized to retain a portion of the receipts based on BLM’s cost of collections.
- ***General Treasury***—Any remaining receipts are deposited in the Treasury.

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